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INDIANA UTILITY REGULATORY COMMISSION

INDIANA UTILITY

REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC)
COMPANY d/b/a VECTREN ENERGY DELIVERY OF)
INDIANA, INC. ("VECTREN SOUTH - ELECTRIC") FOR (1))
AUTHORITY TO INCREASE ITS RATES AND CHARGES)
FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF)
NEW SCHEDULES OF RATES AND CHARGES)
APPLICABLE THERETO; (3) INCLUSION IN ITS BASE)
RATES OF COSTS ASSOCIATED WITH CERTAIN)
PREVIOUSLY APPROVED QUALIFIED POLLUTION)
CONTROL PROPERTY PROJECTS; (4) AUTHORITY TO)
IMPLEMENT A RATE ADJUSTMENT MECHANISM TO)
TRACK INCREMENTAL CHANGES IN CERTAIN COSTS)
AND REVENUES RELATING TO ITS GENERATING)
FACILITIES; (5) AUTHORITY TO IMPLEMENT A RATE)
ADJUSTMENT MECHANISM TO TRACK INCREMENTAL)
CHANGES IN NON-FUEL RELATED MIDWEST)
INDEPENDENT TRANSMISSION SYSTEM OPERATOR,)
INC. ("MISO") CHARGES AND PETITIONER'S)
TRANSMISSION REVENUE REQUIREMENT; (6))
APPROVAL AS AN ALTERNATIVE REGULATORY PLAN)
PURSUANT TO IND. CODE § 8-1-2.5-6 OF A RETURN ON)
EQUITY TEST TO BE USED IN LIEU OF THE STATUTORY)
NET OPERATING INCOME TEST IN ITS FUEL)
ADJUSTMENT CHARGE PROCEEDINGS; (7) APPROVAL)
OF REVISED DEPRECIATION ACCRUAL RATES; (8))
APPROVAL OF THE CLASSIFICATION OF PETITIONER'S)
FACILITIES AS TRANSMISSION OR DISTRIBUTION IN)
ACCORDANCE WITH THE FEDERAL ENERGY)
REGULATORY COMMISSION'S SEVEN FACTOR TEST;)
AND (9) APPROVAL OF VARIOUS CHANGES TO ITS)
TARIFF FOR ELECTRIC SERVICE INCLUDING NEW)
INTERRUPTIBLE AND ECONOMIC DEVELOPMENT)
RIDERS.)

CAUSE NO. 43111

STIPULATION AND SETTLEMENT

The Indiana Office of Utility Consumer Counselor ("OUCC"), Intervenor Industrial Group ("IG"), and Vectren Energy Delivery of Indiana, Inc., a/k/a Southern Indiana Gas and Electric Company, Inc. ("Company" or "Vectren South")

(collectively, the "parties"), in the interest of efficiency and in order to consider a number of policy issues raised in the Company's testimony, have devoted significant time to the review of data and discussion of issues, and have succeeded in reaching agreement on all issues in this proceeding and therefore stipulate and agree to the terms and conditions set forth below.

In this proceeding, this Stipulation follows the initial hearing on Vectren South's Case-In-Chief, the OUCC's and IG's filing of testimony in response to the Company's case, and the Company's filing of rebuttal testimony. Those filings framed the discussions between the parties, and formed the basis for the parties to reach agreement on the terms reflected in this Stipulation. As set forth in Appendices A, B and C, the parties have negotiated terms that resolve all issues related to the revenue requirement. Specifically, as to pro forma adjustments to the test year proposed in this case, with a few exceptions the agreed upon adjustments either reflect the testimonial rebuttal position of the Company or the testimonial position of the OUCC, and thus are founded upon documented positions that are in the record in this proceeding. The parties have agreed that the OUCC's and IG's testimony, and the Company's rebuttal testimony, will be submitted into the record in support of this Stipulation.

The terms of the Stipulation are as follows:

1. Rate Increase.

Petitioner shall be authorized to increase its basic rates and charges (collectively "rates") for electric utility service. The rates shall be designed to produce base

revenues of \$479,915,205. The increase provides for additional annual revenues of \$67,255,394 or \$60,794,647, this lesser amount being net of the expected credit in the first year as municipal contract revenues are passed back to customers. Based on additional revenues of \$60,798,647, the overall revenue increase is approximately 15%. The base rate increase reflects the roll-in of certain NOx and multi-pollutant control equipment capital and operating costs currently being recovered under Ind. Code §8-1-8.8 et. seq., as well as the recovery of deferred Demand Side Management costs, deferred MISO costs and base amounts of purchase power demand costs. These rates reflect allocation of the revenue increase among all rate classes based on a Settlement cost of service, including a 25% subsidy reduction.

The agreed-upon rate increase reflects the following original cost rate base, cost of capital and financial results (See Appendices A & B) which the Parties agree are reasonable for purposes of compromise and settlement:

Rate Base as of October 31, 2006

	\$(000's)
Utility Plant in Service	\$1,783,735
Less: Accumulated	
Depreciation	812,809
Net Utility Plant	970,926
Materials and Supplies	42,987
DSM Regulatory Asset	29,156
Other Regulatory Assets	650
Total	<u><u>\$1,043,719</u></u>

Capital Structure as of March 31, 2006

	Amount (\$000's)	Weight	Cost	Weighted Cost
Common Equity	\$ 549,508	47.05%	10.40%	4.89%
Long Term Debt	451,347	38.65%	6.04%	2.34%
Customer Deposits	5,601	0.48%	5.39%	0.03%
Cost Free Capital	152,477	13.06%	0.00%	0.00%
Post 1970 JDITC	8,920	0.76%	8.43%	0.06%
	<u>\$1,167,853</u>			<u>7.32%</u>

Pro Forma Proposed Rates

	\$(000's)
Revenue	\$ 479,915
Gas Cost	158,632
Gross Margin	<u>321,283</u>
O&M	131,232
Depreciation	64,274
Income Taxes	34,501
Other Taxes	14,876
Total Operating Expense	<u>244,833</u>
Net Operating Income	<u>\$ 76,400</u>

Authorized Return. Effective upon implementation of the rates, which shall be set forth in a form of tariff for Electric Service, I.U.R.C. No. E-12, ("Tariff") described hereafter and submitted with the testimony filed in support of the Settlement, the Company's authorized return for purposes of the earnings test component of the gas cost adjustment (Ind. Code §§ 8-1-2-42(g)(3)(C) and -42.3) shall be \$76,400,199. (See Appendix A, page 3 of 3). This represents a return of approximately 7.32% on an original cost rate base of \$1,043,718,562. The Parties agree, solely for purposes of settlement and compromise, that this represents a reasonable return on Company's investment in used and useful property, plant and equipment.

Depreciation Rates. Vectren South's depreciation rates have been adjusted to the asset category-specific depreciation rates consistent with the Company's Rebuttal Testimony in this Cause.

2. Pro Forma Adjustments.

All the agreed upon adjustments are set forth in Appendix C. The OUCC filed testimony contesting a number of the Company's proposed adjustments. As set forth in Pub. Ex. 6, Schedule TSC-31, the OUCC recommended almost \$11 million of adjustments to the Company's O&M pro formas. The Company responded in its rebuttal filing, supporting many of the disputed pro forma amounts but also agreeing to decrease its O&M pro formas in the case by approximately \$5.8 million. The parties then negotiated the remaining pro forma differences, with the Company decreasing its O&M pro formas by an additional \$1.6 million in the Settlement. Appendix C provides a comparison of the Company's pro forma adjustments as set forth in its original case-in-chief to the OUCC's filed positions, as well as the Company's positions on rebuttal, and to the final negotiated Settlement amounts for each pro forma adjustment. Intervenor IG did not file testimony related to the Company's pro formas.

The material pro forma reductions as a result of both the Company's rebuttal and settlement concessions are discussed specifically below. While an explanation of these individual adjustments is provided, the negotiated amounts represent agreements reached by the parties as part of the overall settlement package of terms.

Fuel Handling Expense (A11)

The Company included a \$332,391 pro forma adjustment based on projected increases in fuel prices. The OUCC eliminated the adjustment based on 2006 expense data. The Company agreed to remove the entire pro forma amount.

Ongoing MISO Day 2 Costs (A13)

The Company projected ongoing Day 2 costs based on test year experience. The OUCC used 2006 cost information to reduce the base rate amount of MISO Day 2 costs from \$5,420,266 to \$2,668,969. The Company agreed to this reduction. The parties have agreed that variances from base rate amounts in ongoing Day 2 costs will be tracked.

MISO Day 2 Costs Deferral Amortization (A14)

The Company based its \$4,682,823 pro forma adjustment on a 3 year amortization of its deferred MISO Day 2 costs. The OUCC reduced this amount to \$2,997,298 due mostly to use of a 4 year amortization period. The Company has agreed to use a 4 year amortization period and reflected that period, plus a recent updated cost estimate, to arrive at an agreed upon adjustment of \$3,063,416.

Labor Adjustments (A16, A17)

The Company adjusted test year long-term and short-term incentive compensation costs to reflect "target" levels of payouts to employees. Target is

intended to reflect payment of market compensation to employees as part of their overall compensation. The amount of annual incentives will vary above or below target based on the achievement of pre-established metrics that are used to measure performance; this is why such compensation is deemed to be "at risk." The OUCC testimony reduced these incentive compensation adjustments to reflect projected 2006 below target results under the incentive plans. The Company's rebuttal supported use of target levels for ratemaking purposes and for purposes of settlement the OUCC agreed to the pro forma adjustments. This use of target levels of compensation is consistent with the last two Vectren South – Gas rate case settlements.

Additional Employees (A21)

Vectren South proposed the addition of 36 new employees (unrelated to the aging workforce issue) throughout the Company at a cost of \$1,671,876. The OUCC reduced this pro forma to \$182,679, which reflected only the seven (7) post-test year positions filled as of October 2006. On rebuttal, Vectren South reflected that as of March 2007, 11 of the positions had been filled. Of the remaining 25 proposed new employees, Vectren South agreed to eliminate 13, but continued to support the need for 12 more employees. Vectren South also reflected that with the shut down of Culley Unit 1, and the inability to agree with the union on the reassignment of 12 employees, it would be eliminating the 12 Culley Unit 1 employees at a cost savings of (\$840,985). In its case-in-chief, the Company had already reflected non-labor cost savings due to the Culley Unit 1 shut down of (\$794,573) (see Adjustment A28). On rebuttal, Vectren South used

the Culley Unit 1 labor savings to offset most of the cost of the 12 additional employees the Company proposed to hire, resulting in a remaining net pro forma of \$344,190. After further discussing the remaining as yet unhired employees in this category, most of whom are engineers to support increased levels of maintenance activities agreed to in other pro formas, the Company and OUCC reached agreement on inclusion of the cost of 11 employees, resulting in the final Settlement adjustment amount of \$217,094. The eleven additional employees are reflected on Pet. Ex. MSH-3S, Adjustment A21-S, p.2.

Aging Workforce—Power Supply (A22)

The Company proposed to hire a number of apprentices in the power supply area to be prepared for the wave of retirements that will hit these key areas in the near future. The apprentice programs are designed to provide trained employees to replace very experienced retirees. The OUCC agreed with this concept, but reduced the pro forma adjustment from \$1,392,899 to \$835,330 to reflect offsetting cost savings due to retirements and to reduce the number of power plant trainers being added to assist in the apprenticeship process. On rebuttal, the Company agreed to the majority of the OUCC's recommended reductions, but proposed to retain one of the three training clerical employees eliminated by the OUCC to provide necessary assistance to the new training efforts. Thus, the Company reduced its pro forma from \$1,392,899 to \$909,018. In Settlement, the parties agreed to set the pro forma at \$885,351.

Aging Workforce—Energy Delivery (A23)

The Company proposed to hire apprentice line specialists, electricians, engineers and trainers in advance of the retirements in its workforce to maintain a skilled workforce. The Company also included new employees and programs in its Human Resources and Safety departments to support these initiatives, as well as to generally upgrade the performance in these areas, for a total pro forma amount of \$1,719,580. Again, the OUCC agreed with the need to hire apprentices in key operational job categories, but recommended elimination of some internal labor costs, three apprentices being hired to cover anticipated attrition during the course of the apprenticeship programs, and all of the Human Resources/Safety costs. The OUCC supported a pro forma of \$1,165,478, \$554,102 less than the Company's proposal. In rebuttal, the Company accepted most of these reductions, but preserved certain HR/Safety costs as necessary to address necessary work requirements. The retained HR/Safety costs represent allocated costs consistent with the same HR/Safety costs agreed to in the Vectren-South-Gas Settlement. The final pro forma amount in this area is \$1,287,995, which was the Company's position on rebuttal.

Environmental Chemical Expenses/Catalyst Expenses (A24, A25)

The Company uses various chemicals and catalyst in its pollution control processes at its baseload coal plants. Based on projected cost increases driven by increasing compliance standards, catalyst aging and rising chemical costs associated with higher fuel prices, the Company included pro forma adjustments of \$2,308,679 for chemicals and \$2,540,000 for catalyst. To address volatility associated with these costs, the Company also requested a tracking mechanism.

The OUCC based its recommendations on 2007 contract data and other available 2007 cost projections, and reduced the chemical and catalyst pro formas to \$1,114,752 and \$1,863,500 respectively, a combined reduction of \$1,870,427. The OUCC also rejected the proposed tracking of these O&M costs through the GCRA. On rebuttal, the Company accepted the reduced pro formas, but argued that a tracking mechanism should be approved. The Settlement eliminates the tracker and adopts the OUCC's position related to the costs.

Energy Delivery Maintenance Programs (A33, A34, A35, A36)

Each program is addressed separately below. As a general matter, OUCC witness Soller provided testimonial recommendations that relate to all four maintenance programs based on her prior engineering experience and her extensive dialogue with Company operations personnel over a period of six months. She recommended a written reporting process, update meetings with the OUCC, progress reviews with reference to certain agreed to metrics, and as reflected in the individual program adjustments, a more gradual approach to implementation. These recommendations have been adopted as part of the Settlement.

Substations Inspection Programs (A33)

The Company proposed a program that included periodic breaker inspections, painting, infrared scanning and other maintenance activities at a cost of \$1,005,479. Based on the need for more detailed explanation, the OUCC eliminated the breaker inspections, recommended annual infrared scans instead

of semi-annual, and extended the painting cycle from 10 to 15 years, thereby reducing the pro forma to \$428,484. On rebuttal, the Company provided further explanation of its breaker inspections, and agreed to the change in frequency related to both infrared scans and painting and reduced the pro forma to \$823,192. After further discussion and some changes to the timing of breaker inspections to comply with recently approved NERC reliability standards, the parties agreed to a pro forma amount of \$751,068.

Underground Facilities Maintenance (A34)

The Company proposed to engage in regularly scheduled inspections of its downtown Evansville underground network given age and increasing usage at a cost of \$354,280. The OUCC agreed with the program but eliminated costs it interpreted to be non-incremental internal labor to arrive at a pro forma of \$271,832. After some clarification of the costs of consultants and Company employees involved in the program, the parties agreed on an amount of \$327,162. This reflected elimination of internal labor costs which the Company still contends are incremental in nature. Similar disputed internal labor costs were removed in the final Settlement from Training (A20), Reliability Studies (A37) and Meter Reading (A41).

Line Clearance (A35)

The Company proposed adoption of a five year cycle for tree trimming on its distribution and transmission system with a pro forma cost of \$1,880,232. The OUCC supported this cycle, but removed \$227,232 based on its calculation of

the cost of the activity. On rebuttal the Company supported the original cost estimate and explained that it incurred \$227,000 of test year expense related to storm damage clearing and not tree trimming, and thus this amount should not be deducted from the pro forma. In Settlement, the Company agreed to the OUCC's reduction and the final pro forma is \$1,653,000.

Overhead Facilities Maintenance (A36)

Vectren South proposed a multifaceted program to enhance its inspection and maintenance of overhead facilities, including annual pole inspections, transmission tower painting, inspections of pole guys and grounding, ongoing inspections and work to improve circuit reliability, infrared inspections of circuits and switches, review and improvement of animal guards and frequently failing system components, and the addition of 10 line specialists (other than to replace retirees) to reduce reliance on contract labor which will likely be harder to find as the aging workforce issue impacts contractors. The pro forma amounted to \$3,160,733.

The OUCC recommended almost \$1.4 million of reductions to this pro forma. These included elimination of additional circuit flyovers and internal labor on several programs, differences in calculation of certain estimates, change in cycle times for infrared inspections, changing the transmission tower painting cycle from 5 to 20 years, and reducing the hiring of 10 new line specialists to three new line specialists.

On rebuttal the Company agreed to reduce the pro forma to \$2,682,530, a reduction of \$478,195. This change reflected a move to a 10 year cycle on tower painting, a change from annual circuit inspections to every two years, cost reductions to reflect reductions in internal labor, and a proposed hiring of 6 new linemen instead of 10.

The Company and OUCC carefully reviewed each program and negotiated further adjustments to several programs, and reduced the number of new linemen to be hired to 5. The final pro forma is \$2,478,136.

Uncollectible Accounts Expense (A40)

The Company based its bad debt expense on a five year historic average percent of revenue (0.38%) while the OUCC proposed use of a more recent three year historic average percent of revenue (0.26%) as of March 2006.

On rebuttal the Company adjusted its pro forma expense from (\$372,306) to (\$661,248) using a percent of revenue of (0.31%) based upon a 3 year average ended December 2006. In Settlement, the Company agreed to the OUCC's three year average and a pro forma of (\$867,578).

Safety Communication Costs (A45)

The Company proposed both a school based safety education program as well as a mass media approach to customer safety education. The OUCC agreed to the school program with a cost of \$120,000, but eliminated the remaining costs claiming that they were primarily marketing costs, which reduced the pro forma

by \$280,000. While the Company defended its entire communication proposal on rebuttal, in the Settlement the Company agreed to the OUCC's positions and a final pro forma of \$120,000.

MISO Day 1 Costs (A48)

The Company proposed recovery of its deferred MISO Day 1 Costs using a four year amortization period. The OUCC reduced the pro forma based on a different estimate of the level of authorized deferrals. In Settlement, the OUCC agreed to the Company's pro forma amount.

Property and Risk Insurance (A50)

The Stipulation reflects agreement on the reduction in this expense due to a reduction in insurance premiums that occurred during the pendency of the case. The resulting pro forma adjustment is \$301,900.

Claims Expense (A51)

The OUCC reduced the Company's claims expense to exclude recovery of an unpaid claim of over \$450,000, and to reflect use of five year amortization of another large claim versus the Company's use of a three year amortization period. This reduced claims expense by \$245,000. On rebuttal, the Company explained that the large unpaid claim had recently been paid and that a three year amortization period made sense, especially in light of the Company's heightened risk due to its recent increase in its liability insurance deductible (the reduced premium cost having been passed on to customers in A50). In

Settlement the Company agreed to use a five year amortization period for large claims and reduced its pro forma from its case-in-chief of (\$678,892) to (\$833,893).

Customer Service Costs (A72)

In response to concerns expressed at the public field hearing and following an extended collaboration between the Company and the OUCC, a number of customer payment method options and complaint handling options were considered. The OUCC and Company have agreed to implement three new customer service options: (1) the installation in the City of Evansville of a centrally located payment kiosk where, with no fee, customers can deposit cash payments in a programmed machine; (2) new payment sites in Evansville and Mt. Vernon where customers can pay gas bills at locations where water bill payments are currently collected; and (3) dedication of 1-2 new employees who will be trained to meet with customers to discuss complaints, thereby providing customers with the opportunity to engage in face to face communication with the Company. Vectren customers will be notified of these options through bill inserts. The cost of these new services, on an allocated basis to Vectren South Electric, is \$93,000. This adjustment is set forth on Pet. Ex. No. MSH-3S, Adjustment A72. The allocated cost of these same new services was included in the Vectren South-Gas Settlement.

Asset Charge (A57)

As reflected in testimony, the parties have agreed on the calculation methodology used to determine this cost (see Pet. Ex. No. MSH-3S, Adjustment 57). The calculation using the agreed upon 10.4% ROE has been performed and is reflected in Appendix C.

Depreciation (A58)

The Company agreed to the OUCC's recommendation to change the depreciation rate for the Fabric Filter installation at Culley Unit 3, changing its depreciation expense pro forma from \$161,266 to (\$59,234). In rebuttal testimony and in settlement discussions the Company and OUCC discussed and reviewed the data used by the Company to support its study, and thereby addressed the OUCC's concerns.

Income Taxes, IURT Taxes (A60, A63 and A64)

There are no differences between the parties on these items which have been determined based upon the settlement amounts in this case.

3. Return on Equity (ROE) Test.

The parties have agreed that the Company's proposed ROE test will not be adopted as a replacement for the existing Net Operating (NOI) test. However, consistent with past adjustments to the Company's level of authorized NOI to accommodate recovery of costs related to its approved NOx and Multi-Pollutant

environmental projects, the parties agree that the Company's authorized NOI for purposes of the NOI test should be similarly adjusted in the future to allow the Company to retain its recovery of costs associated with approved Senate Bill 29 projects (Ind. Code §8-1-8.8 et. seq.), as well as for the agreed upon NOI adjustment associated with the opportunity to retain a share of Non-Firm Wholesale Power Margins (WPM) as described below.

The parties have also agreed that within 30 days of an order in this proceeding, the OUCC will invite the Company and IG, as well as other interested stakeholders, other utilities and the Staff to discuss the relative merits of the NOI earnings test versus an ROE earnings test. The OUCC and/or Company may ultimately file a petition related to the earnings test following these discussions.

4. Generation Cost and Revenue Adjustment (GCRA).

The parties have agreed that the GCRA will be renamed the Reliability Cost and Revenue Adjustment (RCRA) and that changes from the base rate amount of Direct Load Control Billing Credits will be tracked separately under a DSM Adjustment (DSMA). The parties further agree that the Company's proposal to track changes in chemical and catalyst costs will be withdrawn. Therefore, the RCRA will now be used to adjust the Company's rates for the following items:

1. Non-Firm Wholesale Power Margins (WPM)
2. Municipal Wholesale Margins
3. Environmental Emission Allowance (EEA) Credits
4. Interruptible Sales billing credits

5. Purchased Power Non-Fuel Costs

Two of these items, Municipal Wholesale Margins and EEA credits, represent pass through of cost reductions to customers. The Company will provide 100% of the margins from its Municipal Wholesale contracts to customers (following an order in this case) during the remaining duration of these contracts in 2007 and 2008, including sales to municipal suppliers during this period as described in Jochum's rebuttal testimony. The Company will also credit customers for 100% of the market value of all EEAs it uses to back its WPM sales. The EEA credits reflect use of SO₂ and NO_x allowances, and at the time required for compliance in the future, this adjustment will also reflect the value of mercury allowances.

The Company will file the RCRA semi-annually (every 6 months). The first 6 months of estimated credits from municipal wholesale sales and EEA credits will be filed at the same time new rates from this proceeding go into effect. In each new tracker filing, the Company will include a forecast of the amount of future RCRA filings.

The sharing of WPM results may also provide a credit or a charge to customers depending upon the level of such margins achieved by the Company compared to the base rate revenue requirement credit of \$10.5 million. The WPM sharing mechanism is described further below.

To the extent the Company incurs purchased power demand costs different from its base level of costs, those differences will be tracked under the RCRA. Also, to the extent the Company incurs Interruptible Sales billing credits different from

the base level of such billing credits, those differences will be tracked under the RCRA. Currently, the Company provides a billing credit to one large interruptible customer.

5. Non-Firm Wholesale Power Margins (WPM).

In its case-in-chief the Company proposed to follow the approved Duke Indiana model and share WPM results 50/50 with customers. The Company “embedded” as a credit to its revenue requirement in this case \$10.5 million, the pro forma amount of WPM. Under the proposal, the Company and customers share equally in results above and below that \$10.5 million target. The parties have reached agreement that the Company should retain an incentive to maximize WPM results, and that risk and reward in this area should be shared. Therefore, under the Settlement, this 50/50 sharing proposal has been adopted, with the customer share of WPM to flow through the RCRA. The parties recognized that the Company’s current NOI under earnings bank of (\$202 million) will be eliminated upon receipt of an order in this case, thereby potentially reducing the Company’s opportunity to retain its potential share of WPM proceeds. Thus, the incentive opportunity may be effectively lost and customers could receive both their 50% share of additional WPM proceeds as well as the Company’s share of WPM proceeds. To address this particular set of circumstances in terms of the loss of a large historic under earnings bank, and recognizing the large capital needs, environmental risks and other challenges facing the Company, which is a very small electric utility, the parties have agreed that for four years (16 FAC quarters) following the order herein, the Company will be allowed up to a \$3

million increase to its authorized NOI for purposes of calculating the NOI earnings test, but only to the extent that the Company's share of WPM proceeds recorded on the Company's books have created its over earning status. This incremental amount provides the ability to retain the 50% share WPM proceeds.

6. MISO Cost and Revenue Adjustment (MCRA).

The parties have reached agreement on the tracking of changes in the base expense amounts of non-fuel MISO costs, costs associated with MISO Day 1 and Day 2 which are not already recovered via the FAC.

In this case, the Company had also proposed to recover its costs associated with future investments in transmission infrastructure in furtherance of FERC's policy to support increased investment in the transmission grid. On rebuttal, the Company divided its transmission investment into three distinct categories: (1) existing investment included in retail rate base, (2) Regional Expansion Criteria and Benefit Process (RECB) investment, and (3) non-RECB MISO reviewed and approved investment.

With respect to these 3 categories of investment, the parties have agreed as follows: current investment will remain included in retail rate base. RECB costs will be tracked, and non-RECB costs will not be tracked. RECB costs will be charged to the Company under MISO Schedule 26—this will include charges related to the Company's own RECB projects as well as its allocation of costs related to other third party RECB projects. Through Schedule 26, the Company will receive partial cost recovery for its projects from other transmission owners in

the MISO footprint on an allocated basis. The Company will be authorized to retain the allocated portion of cost recovery from native load customers as calculated under Schedule 26 as well as the revenues received from other MISO transmission owners under Schedule 26—all such Schedule 26 recoveries shall be treated as non-jurisdictional and outside the earnings test to allow the Company to recover its costs. The Company's RECB projects will not be included in retail rate base.

The Company will also invest in other reliability projects that do not qualify for RECB treatment, but will be MISO approved (non-RECB projects). The Company has agreed to withdraw its request to recover costs related to such projects between rate cases under its proposed MISO Transmission Component of the MCRA, and has also dropped its alternative request for post-in service AFUDC and deferred depreciation for such projects. With respect to ratemaking related to MISO tariff/costs, nothing in the Settlement should be interpreted to prevent the Company from pursuing cost recovery or different ratemaking treatment in later proceedings based upon newly adopted statutes or orders issued by the FERC or IURC. In future proceedings regarding MISO tariff/cost recovery, nothing in this Settlement will be interpreted to prevent the parties from taking any position with respect to cost recovery proposals.

A representative level of transmission revenues has been included as revenue credits in the Settlement revenue requirements. The parties have agreed to track actual differences from these base rate levels during the first year after the implementation of new rates in this proceeding. Prior to the end of the first year,

the parties will meet to review available data regarding the Company's actual transmission revenues. After review and discussion, the parties will present to the Commission a proposal regarding the future tracking of actual differences from the transmission revenues credited in base rates. That proposal will address the Company's ability to retain the portion of transmission revenues related to its non-RECB transmission investment not otherwise recovered from retail customers. Absent agreement of the parties, any party may file a tracking proposal and revenues will be deferred until further order of the Commission.

The Company will file the MCRA semi-annually (every 6 months). In each new tracker filing, the Company will include a forecast of the amount of future MCRA filings.

7. Future Rate Case and Reporting Commitments.

The parties agree that the Company will file a base rate case no later than December 31, 2012. During this interim period, the Company will provide reports to the OUCC regarding certain system metrics and progress on maintenance programs. The framework related to the timing and contents of such reports is set forth in Appendix D. The various cost recovery trackers agreed to in this Settlement shall remain in effect until a final order in the next rate case. Should the parties reach mutual agreement to extend the deadline for the next rate case, they will inform the Commission of the decision to extend the filing date and the basis thereof prior to December 31, 2012. When Vectren South files its next base rate case, the Company will file two cost of service studies: one using 4CP

to allocate all operating costs, and the other will be the same except for using 12CP to allocate jurisdictional transmission costs. The Company may recommend use of either approach.

8. Cost of Service/Rate Design.

For purposes of settlement only, the Parties have agreed to maintain the existing cost of service allocations, including transmission and generation function allocations based on a 4 coincident peak (4 cp) methodology, and to reflect a 25% subsidy reduction. The revenue responsibility for each rate schedule has been established based on the settlement cost of service. The cost of service allocation reflects the Company's special contract with PPG Industries which has been filed with the Commission pursuant to a separate Settlement Agreement. To the extent the PPG Settlement is not approved, the Company would modify its cost of service study to reflect the implications of continuing to serve PPG at the new base rates.

The settlement rates and charges are reflected in the Revenue Proof to be filed with testimony. Except for Residential Rate A, the Settlement revenue increase for each rate schedule was distributed among the rate schedule's Customer Facilities Charge, Demand Charge (where applicable), and Energy Charges rate blocks in the same manner as in the Company's case-in-chief, continuing the objective of having the bill impacts to any customer be no more than approximately two times the overall rate schedule increase. For the Residential Rate A, the Customer Facilities Charges was established at \$5.50 and the

Energy Charge rate blocks were increased from present rates on an equal percentage basis to recover the remaining rate class increase.

9. Tariff

A Settlement Tariff will be filed in testimony. The settlement tariff includes a number of changes as proposed by the Company in its case-in-chief as well as updated tariff sheets reflecting tariff changes approved by the Commission after the initiation of this rate proceeding. The tariff changes are summarized below.

Rate Schedule Changes

1. Rate and Charges revisions to reflect the settlement rates and charges.
2. Rate Schedule revisions, deletions and additions including;
 - a. Addition of a rate step to Rate EH (Home Heating).
 - b. Modified Applicability section of Rate B (Water Heating) to clarify eligibility.
 - c. Splitting Rate GS (General Service) into two Rate Schedules - Rate SGS (Small General Service) and Rate DGS (Demand General Service) and revising both rate structures, including revising the Determination of Billing Demand section for DGS.
 - d. A revision to the Determination of Billing Demand for Rate OSS (Off Season Service).

- e. Revisions to Rate LP (Large Power) to :
 - i. Eliminate grandfathering of former Rate PP-2 customers.
 - ii. A revision to the Minimum Bill section.
 - iii. A revision to the Determination of Billing Demand Section.
 - iv. Modified Contract section to require a minimum three-year initial term
- f. Revised Rate BAMP (Backup, Auxiliary, and Maintenance Power Services) such that the Maintenance Capacity and Energy Charges will refer to the LP rates.
- g. Elimination of Street Lighting Rate Schedules SL-4 and SL-6.
- 3. The addition of Availability sections and the additions of Appendices and Riders sections to each Rate Schedule to more readily identify Adjustments and available Riders applicable to customers in each Rate Schedule.

Rider Changes

- 4. The addition of Rider IC (Interruptible Contract Rider) and Rider IO (Interruptible Option Rider) to offer interruptible service to customers.
- 5. The addition of Rider ED (Economic Development Rider) and Rider AD (Area Development Rider) to be available to qualifying customers new to Vectren South's service area or with increased loads at existing locations.

6. The elimination of Rider HLF-1 and the closing to new customers of Rider LP-1 (Energy Incentive Riders) which are being replaced with the two new economic development Riders.
7. The addition of Rider DLC (Direct Load Control Rider) to reflect credits applicable to customers participating in the Company's Summer Cycler DLC program .

Appendices Changes

8. The revision of Appendix B (Demand-Side Management Adjustment, the "DSMA") from a DSM lost revenue tracker, to a Direct Load Control credit tracker.
9. The elimination of Appendix C – Clean Air Act Amendment Adjustment, by rolling the credits tracked by it into Appendix J, the RCRA.
10. The addition of language providing more detailed descriptions for the recurring charges already reflected in Appendix D, Other Charges.
11. The eliminations of NOx-related Appendix E (Qualified Pollution Control Property – Construction Cost Adjustment) and Appendix F (Qualified Pollution Control Property – Operating Expense Adjustment) by rolling the costs recovered via these trackers into base rates.
12. The addition of Appendix I (MISO Cost and Revenue Adjustment, the "MCRA") to track certain costs and revenues related to MISO.

13. The addition of Appendix J (Reliability Cost and Revenue Adjustment, the "RCRA") to track certain costs and revenues related to the reliability of Vectren South's power supply portfolio.

Terms and Conditions Changes

14. The addition of item a.6 to Rule 1, Application of Rates, to clarify that averages may not be avoided by switching service from the name of a person still residing at the premise.
15. The revision of language describing the Equal Payment Plan in Rule 10d.
16. The addition of details regarding Vectren South's Curtailment Procedures in Rule 19.
17. The elimination of Rule 21 – Utility Residential Weatherization Program.

Other Miscellaneous Tariff Changes

18. Revision to the tariff page numbering system to facilitate future updates.
19. The addition of a Definitions Section to contain definitions of words and terms that reoccur in the Tariff. The defined terms are shown with initial capital letters when they later appear in the Tariff.
20. Other minor changes in the nature of housekeeping throughout the Tariff.

Tariff Sheets Revisions Approved by the Commission Subsequent to Case-In-Chief

- 21. Addition of Rate S (Emergency Notification Sirens).
- 22. Additions of Multi-pollutant trackers—Appendix G (QPCP-CC2) and Appendix H (QPCP-OE2).
- 23. Updates to Rate CSP (Cogeneration and Small Power Production) and Rider NM (Net Metering) to reflect changes required by the Interconnection Standards approved by the Commission.

10. Request for Prompt Approval by the Commission.

The parties acknowledge that a significant motivation for the Company to enter into the Settlement is the expectation that an order will be issued promptly by the Commission authorizing increases in its rates and charges. The parties have spent many months reviewing data and negotiating this Settlement in an effort to eliminate time consuming and costly litigation. In particular, the OUCC and Company have reviewed the maintenance programs, and have worked together on the metrics and reporting structure included in the Settlement. The resulting Settlement has reduced the Company's filed request for a rate increase and modified its other requested cost recovery mechanisms. Under these circumstances, the parties ask that their request for prompt approval be seriously considered and acted upon.

11. Stipulation Effect, Scope and Approval.

The parties acknowledge and agree as follows:

(a) The Stipulation is conditioned upon and subject to its acceptance and approval by the Commission in its entirety without any change or condition that is unacceptable to any party. Each term of the Stipulation is in consideration and support of each and every other term.

(b) The Stipulation is the result of compromise in the settlement process and neither the making of the Stipulation nor any of its provisions shall constitute an admission or waiver by any party in any other proceeding. The Stipulation shall not be used as precedent in any other proceeding or for any other purpose except to the extent provided for herein or to the extent necessary to implement or enforce its terms.

(c) The evidence to be submitted in support of the Stipulation constitutes substantial evidence sufficient to support the Stipulation and provides an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of the Stipulation.


(d) The communications and discussions and materials produced and exchanged during the negotiation of the Stipulation relate to offers of settlement and shall be privileged and confidential.

(e) The undersigned represent and agreed that they are fully authorized to execute the Stipulation on behalf of their designated clients who will be bound thereby.

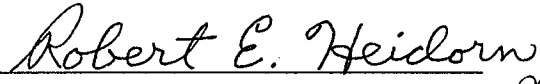
(f) The parties will either support or not oppose on rehearing, reconsideration and/or appeal, an IURC Order accepting and approving this Stipulation in accordance with its terms.

ACCEPTED and AGREED this 20 th day of April, 2007.


INDIANA OFFICE OF UTILITY
CONSUMER COUNSELOR

By: 
Jeffrey M. Reed
Assistant Consumer Counselor

VECTREN ENERGY DELIVERY OF
INDIANA, INC. a/k/a SOUTHERN
INDIANA GAS AND ELECTRIC
COMPANY

By:  *DWM*
Robert E. Heidorn

Intervenor Industrial Group

By: 
Timothy L. Stewart

INDS01 DWM STIPULATION AND SETTLEMENT AGREEMENT.DOC

VECTREN SOUTH
ELECTRIC TARIFF
ACTUAL AND PRO FORMA STATEMENT OF OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Line No.	Description	Actual Per Books	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
<u>Operating Revenues</u>								
1	Electric Revenue	\$ 434,583,374			\$ 412,659,811	\$ 67,255,394	A65-S	\$ 479,915,205
2	Normal Weather		(1,355,531)	A01				
3	Annualized Days of Service		1,713,062	A02				
4	Customer Count		784,530	A03				
5	Large Customer Changes		711,861	A04				
6	Miscellaneous Revenue		178,857	A05				
7	Unbilled Revenue		(1,455,828)	A06				
8	Cost of Fuel		13,695,641	A07				
9	Wholesale Power Marketing Revenue		(10,200,159)	A08				
10	Municipal Customer Revenue		(25,911,843)	A09				
11	DSM Lost Margin Revenue		(84,153)	A10				
12	Total	434,583,374	(21,923,563)		412,659,811	67,255,394		479,915,205
13	<u>Fuel and Purchased Power</u>	153,068,787			158,632,230			158,632,230
14	Normal Weather		(336,977)	A01				
15	Annualized Days of Service		885,661	A02				
16	Customer Count		200,633	A03				
17	Large Customer Changes		(207,375)	A04				
18	Cost of Fuel		13,494,389	A07				
19	Wholesale Power Marketing Fuel Expenses		(4,678,890)	A08				
20	Municipal Customer Fuel Expenses		(13,241,883)	A09				
21	Fuel Handling Expenses		-	A11				
22	Purchased Power Demand Costs		3,715,500	A12				
23	Ongoing MISO Day 2 Costs		2,668,969	A13				
24	MISO Day 2 Costs Deferral Amortization		3,063,416	A14				
25		153,068,787	5,563,443		158,632,230	-		158,632,230
26	Gross Margin	\$ 281,514,588	\$ (27,487,006)		\$ 254,027,582	\$ 67,255,394		\$ 321,282,976

VECTREN SOUTH
ELECTRIC TARIFF
ACTUAL AND PRO FORMA STATEMENT OF OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Line No.	Description	Actual Per Books	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
Operation and Maintenance Expenses								
27	Operations and Maintenance Expenses	\$ 96,293,286			\$ 122,424,250			122,673,095
28	Labor and Labor Related Costs							
29	Labor Adjustments for Existing Headcount		2,960,133	A15				
30	Labor-Related Costs		617,289	A16				
31	Other Compensation		311,785	A17				
32	Pension Expense		341,067	A18				
33	Postretirement Medical Expense		(294,807)	A19				
34	Training Expense		141,468	A20-S				
35	Additional Employees		217,094	A21-S				
36	Aging Workforce Related Costs							
37	Power Supply		885,351	A22				
38	Energy Delivery		1,287,995	A23				
39	Operation and Maintenance Programs							
40	Environmental Chemical Expenses		1,114,752	A24				
41	Catalyst Expenses		1,863,500	A25				
42	Ash Disposal Costs		1,500,000	A26				
43	By Product Sales		984,850	A27				
44	Culley Unit 1 Expense Reduction		(794,573)	A28				
45	Turbine Maintenance		3,359,950	A29				
46	Flue Gas Desulphurization Structural Maintenance		1,075,000	A30				
47	Wholesale Power Marketing Trading Expenses		(278,904)	A31				
48	Boiler Outage and Maintenance		1,078,855	A32				
49	Substation Inspection Programs		751,068	A33-S				
50	Underground Facilities Maintenance		327,162	A34-S				
51	Line Clearance		1,653,000	A35-S				
52	Overhead Facilities Maintenance		2,478,136	A36-S				
53	Reliability Studies and Planning		93,750	A37-S				
54	Ongoing Demand Side Management Programs		947,582	A38				
55	Ongoing MISO Day 1 Administrative Costs		1,342,877	A39				
56	Uncollectible Accounts Expense		(867,578)	A40-S				
57	Meter Reading Costs		29,133	A41-S				
58	Miscellaneous Billing Costs		20,715	A42				
59	Sales and Marketing Costs		93,000	A43				
60	Contact Center Costs		157,036	A44				
61	Safety Communication Costs		120,000	A45-S				
62	Information Technology Costs		180,346	A46				
63	Amortization of Deferrals							
64	New Source Review Litigation Costs		985,111	A47				
65	MISO Day 1 Costs		1,501,694	A48				
66	Rate Case Expense		377,333	A49				
67	Other Costs/Adjustments							
68	Property and Risk Insurance		301,900	A50				
69	Claims Expenses		(833,893)	A51-S				
70	Other Cost Reductions		(99,680)	A52				
71	Changes in Cost Allocations		(32,771)	A53				
72	Asset Management Program Costs		103,480	A54				
73	Asset Management Program Savings		(35,923)	A55				
74	Customer Service Costs		93,000	A72				
75	Going Level Uncollectible Accounts					174,864	A66	
76	IURC Fee		73,681	A56		73,981	A67	
77		96,293,286	26,130,964		122,424,250	248,845		122,673,095
78	Asset Charge	8,037,136	521,368	A57-S	8,558,504			8,558,504
79	Total Operations and Maintenance	\$ 104,330,422	\$ 26,652,332		\$ 130,982,754	\$ 248,845		\$ 131,231,599

VECTREN SOUTH
ELECTRIC TARIFF
ACTUAL AND PRO FORMA STATEMENT OF OPERATING INCOME
FOR THE TWELVE MONTH PERIOD ENDING MARCH 31, 2006

Line No.	Description	Actual Per Books	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H
80	Depreciation and Amortization	\$ 58,788,501	(59,234)	A58	\$ 64,274,381			64,274,381
81			5,545,114	A59				
82	Total Depreciation and Amortization	58,788,501	5,485,880		64,274,381	-		64,274,381
Taxes								
83	Income Taxes (Federal and State)	33,129,594	(5,341,392)	A60	7,675,600	5,695,557	A68	34,501,310
84			175	A61		-	A69	
85			(20,112,777)	A62		21,130,153	A70	
86	Other Taxes (IURT and Property Tax)	12,381,146	621,677	A63	13,936,359	939,127	A71	14,875,486
87			933,537	A64				
88	Total Taxes	45,510,740	(23,898,781)		21,611,959	27,764,837		49,376,796
89	Total Operating Expenses	208,629,663	8,239,431		216,869,095	28,013,682		244,882,777
90	Net Operating Income	\$ 72,884,924	\$ (35,726,437)		\$ 37,158,487	\$ 39,241,712		\$ 76,400,199

**VECTREN SOUTH
ELECTRIC TARIFF**
Calculation of Proposed Revenue Increase
Based on Pro Forma Operating Results
Original Cost Rate Base Estimated at October 31, 2006

Revenue Increase Based on Net Original Cost Rate Base

1	Net Original Cost Rate Base				\$	1,043,718,562
2	Rate of Return					<u>7.32%</u>
3	Required Net Operating Income					76,400,199
4	Pro Forma Net Operating Income					<u>37,158,487</u>
5	Increase in Net Operating Income (NOI Shortfall)					39,241,712
6	Effective Incremental Revenue/NOI Conversion Factor					<u>58.3%</u>
7	Increase in Revenue Requirement (Based on Net Original Cost Rate Base) (Line 5 / Line 6)				\$	<u><u>67,255,394</u></u>
8	One		1.000000			
9	Less: IURC Fee		0.001100			
10	Less: Bad Debt		<u>0.002600</u>			
11	One Less IURC Fee and IURT			0.996300		
12	One	1.000000				
13	Less: Bad Debt	<u>0.002600</u>				
14	Taxable Adjusted IURT		0.997400			
15	IURT Rate		<u>0.014000</u>			
16	Adjusted IURT			0.013964		
17	One	1.000000				
18	Less: Bad Debt	0.002600				
19	Less: IURC Fee	<u>0.001100</u>				
20	Taxable Adjusted Gross Income Tax		0.996300			
21	Adjusted Gross Income Tax Rate		<u>0.085000</u>			
22	Adjusted Gross Income Tax			<u>0.084686</u>		
23	Kentucky Apportionment		0.000538			
24	Kentucky State Income Tax Rate		0.070000			
25	Effective Kentucky Income Tax Rate			0.000038		
26	Kentucky Coal Tax Credit Effect			-0.000038		
27	Line 11 less line 22 less line 25 less line 26				0.897651	
28	One		1.000000			
29	Less: Federal Income Tax Rate		<u>0.350000</u>			
30	One Less Federal Income Tax Rate			<u>0.650000</u>		
31	Effective Incremental Revenue/NOI Conversion Factor (line 27 times line 30)					<u><u>58.3%</u></u>

**VECTREN SOUTH
ELECTRIC TARIFF
PRO FORMA ADJUSTMENT TO OPERATING INCOME**

Statement of Electric Property
Original Cost Rate Base at October 31, 2006

Line No.	Activity (FERC) No.	Description	Electric Plant Per Books at October 31, 2006	Adjustments and Eliminations	As Adjusted Pro Forma Rate Base at October 31, 2006
		<u>Utility Plant</u>			
1	101	In Service - Unitized	\$ 1,312,023,679	\$ -	\$ 1,312,023,679
2	105	Property Held for Future Use	3,163,409	(3,163,409)	\$ -
3	106	Completed Const. Not Classified	421,191,296	-	\$ 421,191,296
4	106	Addition of Fabric Filter at Culley Unit 3 (February 2007)	-	50,519,592	\$ 50,519,592
5	107	Const. Work in Progress	66,962,032	(66,962,032)	\$ -
6			1,803,340,416	(19,605,849)	\$ 1,783,734,567
7	108	<u>Accumulated Depreciation</u> Utility Plant	(812,808,720)	-	\$ (812,808,720)
8		Net Utility Plant	990,531,696	(19,605,849)	\$ 970,925,847
		<u>Material & Supplies (13 Month Average)</u>			
9	154	Utility Material & Supplies	22,167,395		\$ 22,167,395
10	163	Stores Expense	3,101,884		\$ 3,101,884
11	151	Fuel Stock	17,600,522		\$ 17,600,522
12	158	Allowance Inventory	117,419		\$ 117,419
13		Total Material & Supplies	42,987,220		\$ 42,987,220
14	182	DSM - Post 1994 Regulatory Asset	27,611,703		\$ 27,611,703
15	182	DSM - Pre 1994 Regulatory Asset	1,543,877		\$ 1,543,877
16	182	MISO Day 2 Startup Costs	649,916		\$ 649,916
17		TOTAL	\$ 1,063,324,412	\$ (19,605,849)	\$ 1,043,718,562

**VECTREN SOUTH
ELECTRIC TARIFF**
Capital Structure and Cost of Capital
Twelve months ending March 31, 2006

Line No.	Type of Capital	Amount (\$000's)	Percent	Cost	WCOC
1	Long-Term Debt				
2	Publicly Held	\$ 228,165	19.54%		
3	Notes to VUHI	223,182	19.11%		
4	Total Long-Term Debt	\$ 451,347	38.65%	6.04%	2.33%
5	Common Equity				
6	Common Stock	\$ 273,263	23.40%		
7	Retained Earnings	274,999	23.55%		
8	Accumulated Comprehensive Income	1,246	0.11%		
9	Common Shareholder's Equity	\$ 549,508	47.05%	10.40%	4.89%
10	Investor Provided Capital	\$ 1,000,855	85.70%		7.23%
11	Customer Deposits	\$ 5,601	0.48%	5.39%	0.03%
12	Cost Free Capital				
13	Deferred Taxes	\$ 138,730	11.88%		
14	Customer Advances for Construction	2,211	0.19%		
15	SFAS 106	11,536	0.99%		
16	Total Cost Free Capital	\$ 152,477	13.06%	0.00%	0.00%
17	Job Development Investment Tax Credit (Post-1971)	\$ 8,920	0.76%	8.43%	0.06%
18	Total Capitalization	<u>\$ 1,167,853</u>	<u>100.00%</u>		
19	Rate of Return				<u>7.32%</u>
Investor Provided Capital					
		Amount (\$000's)	Percent	Cost	WCOC
20	Long-Term Debt	\$ 451,347	45.10%	6.04%	2.72%
21	Common Equity	549,508	54.90%	10.40%	5.71%
22	Total Capitalization	<u>\$ 1,000,855</u>	<u>100.00%</u>		<u>8.43%</u>
Interest Synchronization					
			Percent	Cost	Weighted Cost
23	Long-term Debt		38.65%	6.04%	2.33%
24	Customer Deposits		0.48%	5.39%	0.03%
25	Interest Component of ITC		0.76%	6.04%	0.05%
26	Total				2.41%
27	Original Cost Rate Base				\$ 1,043,718,562
28	Synchronized Interest Expense				<u>\$ 25,153,617</u>

VECTREN SOUTH
ELECTRIC TARIFF
SETTLEMENT SCHEDULE OF PRO FORMA ADJUSTMENTS

Line No.	Description	AS ORIGINALLY FILED	Ref	OUCC FILED	Ref	REBUTTAL FILED	Ref	SETTLEMENT	Ref	Line No.
		Pro Forma Adjustments Increases (Decreases)		Pro Forma Adjustments Increases (Decreases)		Pro Forma Adjustments Increases (Decreases)		Pro Forma Adjustments Increases (Decreases)		
	A	B	C	D	E	F	G	H		
Operating Revenues										
1	Electric Revenue									1
2	Normal Weather	\$ (1,355,531)	A01	\$ (1,355,531)		\$ (1,355,531)	A01	\$ (1,355,531)	A01	2
3	Annualized Days of Service	\$ 1,713,062	A02	\$ 1,713,062		\$ 1,713,062	A02	\$ 1,713,062	A02	3
4	Customer Count	\$ 784,530	A03	\$ 784,530		\$ 784,530	A03	\$ 784,530	A03	4
5	Large Customer Changes	\$ 711,861	A04	\$ 711,861		\$ 711,861	A04	\$ 711,861	A04	5
6	Miscellaneous Revenue	\$ 178,857	A05	\$ 178,857		\$ 178,857	A05	\$ 178,857	A05	6
7	Unbilled Revenue	\$ (1,455,828)	A06	\$ (1,455,828)		\$ (1,455,828)	A06	\$ (1,455,828)	A06	7
8	Cost of Fuel	\$ 13,695,641	A07	\$ 13,695,641		\$ 13,695,641	A07	\$ 13,695,641	A07	8
9	Wholesale Power Marketing Revenue	\$ (10,200,159)	A08	\$ (10,200,159)		\$ (10,200,159)	A08	\$ (10,200,159)	A08	9
10	Municipal Customer Revenue	\$ (25,911,843)	A09	\$ (25,911,843)		\$ (25,911,843)	A09	\$ (25,911,843)	A09	10
11	DSM Lost Margin Revenue	\$ (84,153)	A10	\$ (84,153)		\$ (84,153)	A10	\$ (84,153)	A10	11
12	Total	(21,923,563)		(21,923,563)		(21,923,563)		(21,923,563)		12
Fuel and Purchased Power										
13	Normal Weather	\$ (336,977)	A01	\$ (336,977)		\$ (336,977)	A01	\$ (336,977)	A01	13
14	Annualized Days of Service	\$ 885,661	A02	\$ 885,661		\$ 885,661	A02	\$ 885,661	A02	14
15	Customer Count	\$ 200,633	A03	\$ 200,633		\$ 200,633	A03	\$ 200,633	A03	15
16	Large Customer Changes	\$ (207,375)	A04	\$ (207,375)		\$ (207,375)	A04	\$ (207,375)	A04	16
17	Cost of Fuel	\$ 13,494,389	A07	\$ 13,494,389		\$ 13,494,389	A07	\$ 13,494,389	A07	17
18	Wholesale Power Marketing Fuel Expenses	\$ (4,678,890)	A08	\$ (4,678,890)		\$ (4,678,890)	A08	\$ (4,678,890)	A08	18
19	Municipal Customer Fuel Expenses	\$ (13,241,883)	A09	\$ (13,241,883)		\$ (13,241,883)	A09	\$ (13,241,883)	A09	19
20	Fuel Handling Expenses	\$ 332,391	A11	\$ -		\$ -	A11-R	\$ -	A11	20
21	Purchased Power Demand Costs	\$ 3,715,500	A12	\$ 3,715,500		\$ 3,715,500	A12	\$ 3,715,500	A12	21
22	Ongoing MISO Day 2 Costs	\$ 5,420,266	A13	\$ 2,668,969		\$ 2,668,969	A13-R	\$ 2,668,969	A13	22
23	MISO Day 2 Costs Deferral Amortization	\$ 4,682,823	A14	\$ 2,997,298		\$ 3,063,416	A14-R	\$ 3,063,416	A14	23
24										24
25		10,266,538		5,497,325		5,563,443		5,563,443		25
26	Gross Margin	\$ (32,190,101)		\$ (27,420,888)		\$ (27,487,006)		\$ (27,487,006)		26

**VECTREN SOUTH
ELECTRIC TARIFF
SETTLEMENT SCHEDULE OF PRO FORMA ADJUSTMENTS**

Line No.	Description	AS ORIGINALLY FILED		Ref	OUCC FILED		Ref	REBUTTAL FILED		Ref	SETTLEMENT		Ref	Line No.
		Pro Forma Adjustments Increases (Decreases)			Pro Forma Adjustments Increases (Decreases)			Pro Forma Adjustments Increases (Decreases)			Pro Forma Adjustments Increases (Decreases)			
	A	B	C		D			E		F	G		H	
Operation and Maintenance Expenses														
27	Operations and Maintenance Expenses													27
28	Labor and Labor Related Costs													28
29	Labor Adjustments for Existing Headcount	\$ 2,960,133	A15	\$	2,968,911	\$		2,960,133	A15	\$	2,960,133	A15		29
30	Labor-Related Costs	\$ 617,289	A16	\$	148,786	\$		617,289	A16	\$	617,289	A16		30
31	Other Compensation	\$ 311,785	A17	\$	(492,277)	\$		311,785	A17	\$	311,785	A17		31
32	Pension Expense	\$ 341,067	A18	\$	341,067	\$		341,067	A18	\$	341,067	A18		32
33	Postretirement Medical Expense	\$ (294,807)	A19	\$	(294,807)	\$		(294,807)	A19	\$	(294,807)	A19		33
34	Training Expense	\$ 145,403	A20	\$	133,360	\$		144,270	A20-R	\$	141,468	A20-S		34
35	Additional Employees	\$ 1,671,876	A21	\$	182,679	\$		344,190	A21-R	\$	217,094	A21-S		35
36	Aging Workforce Related Costs													36
37	Power Supply	\$ 1,392,899	A22	\$	835,330	\$		909,018	A22-R	\$	885,351	A22-S		37
38	Energy Delivery	\$ 1,719,580	A23	\$	1,165,478	\$		1,287,995	A23-R	\$	1,287,995	A23		38
39	Operation and Maintenance Programs													39
40	Environmental Chemical Expenses	\$ 2,308,679	A24	\$	1,114,752	\$		1,114,752	A24-R	\$	1,114,752	A24		40
41	Catalyst Expenses	\$ 2,540,000	A25	\$	1,863,500	\$		1,863,500	A25-R	\$	1,863,500	A25		41
42	Ash Disposal Costs	\$ 1,500,000	A26	\$	1,500,000	\$		1,500,000	A26	\$	1,500,000	A26		42
43	By Product Sales	\$ 984,850	A27	\$	984,850	\$		984,850	A27	\$	984,850	A27		43
44	Culley Unit 1 Expense Reduction	\$ (794,573)	A28	\$	(794,573)	\$		(794,573)	A28	\$	(794,573)	A28		44
45	Turbine Maintenance	\$ 3,359,950	A29	\$	3,359,950	\$		3,359,950	A29	\$	3,359,950	A29		45
46	Flue Gas Desulphurization Structural Maintenance	\$ 1,075,000	A30	\$	1,075,000	\$		1,075,000	A30	\$	1,075,000	A30		46
47	Wholesale Power Marketing Trading Expenses	\$ (278,904)	A31	\$	(278,904)	\$		(278,904)	A31	\$	(278,904)	A31		47
48	Boiler Outage and Maintenance	\$ 1,078,855	A32	\$	970,778	\$		1,078,855	A32	\$	1,078,855	A32		48
49	Substation Inspection Programs	\$ 1,005,479	A33	\$	428,484	\$		823,192	A33-R	\$	751,068	A33-S		49
50	Underground Facilities Maintenance	\$ 354,280	A34	\$	271,832	\$		342,037	A34-R	\$	327,162	A34-S		50
51	Line Clearance	\$ 1,880,232	A35	\$	1,653,000	\$		1,880,232	A35	\$	1,653,000	A35-S		51
52	Overhead Facilities Maintenance	\$ 3,160,733	A36	\$	1,773,028	\$		2,682,538	A36-R	\$	2,478,136	A36-S		52
53	Reliability Studies and Planning	\$ 102,500	A37	\$	85,000	\$		102,500	A37	\$	93,750	A37-S		53
54	Ongoing Demand Side Management Programs	\$ 947,582	A38	\$	947,582	\$		947,582	A38	\$	947,582	A38		54
55	Ongoing MISO Day 1 Administrative Costs	\$ 1,342,877	A39	\$	1,342,877	\$		1,342,877	A39	\$	1,342,877	A39		55
56	Uncollectible Accounts Expense	\$ (372,386)	A40	\$	(867,578)	\$		(661,248)	A40-R	\$	(867,578)	A40-S		56
57	Meter Reading Costs	\$ 39,467	A41	\$	-	\$		39,467	A41	\$	29,133	A41-S		57
58	Miscellaneous Billing Costs	\$ 20,715	A42	\$	20,715	\$		20,715	A42	\$	20,715	A42		58
59	Sales and Marketing Costs	\$ 95,090	A43	\$	95,090	\$		93,000	A43	\$	93,000	A43		59
60	Contact Center Costs	\$ 157,036	A44	\$	157,036	\$		157,036	A44	\$	157,036	A44		60
61	Safety Communication Costs	\$ 400,000	A45	\$	120,000	\$		400,000	A45	\$	120,000	A45-S		61
62	Information Technology Costs	\$ 180,346	A46	\$	180,346	\$		180,346	A46	\$	180,346	A46		62
63	Amortization of Deferrals													63
64	New Source Review Litigation Costs	\$ 985,111	A47	\$	985,111	\$		985,111	A47	\$	985,111	A47		64
65	MISO Day 1 Costs	\$ 1,501,694	A48	\$	1,198,460	\$		1,501,694	A48	\$	1,501,694	A48		65
66	Rate Case Expense	\$ 377,333	A49	\$	377,333	\$		377,333	A49	\$	377,333	A49		66
67	Other Costs/Adjustments													67
68	Property and Risk Insurance	\$ 965,406	A50	\$	301,900	\$		301,900	A50-R	\$	301,900	A50		68
69	Claims Expenses	\$ (678,893)	A51	\$	(923,893)	\$		(720,560)	A51-R	\$	(833,893)	A51-S		69
70	Other Cost Reductions	\$ (99,680)	A52	\$	(99,680)	\$		(99,680)	A52	\$	(99,680)	A52		70
71	Changes in Cost Allocations	\$ 21,588	A53	\$	(32,771)	\$		(32,771)	A53-R	\$	(32,771)	A53		71
72	Asset Management Program Costs	\$ 103,480	A54	\$	103,480	\$		103,480	A54	\$	103,480	A54		72
73	Asset Management Program Savings	\$ (35,923)	A55	\$	(35,923)	\$		(35,923)	A55	\$	(35,923)	A55		73
74	Customer Service Costs	\$ -	A72	\$	-	\$		93,000	A72-R	\$	93,000	A72		74
75	Going Level Uncollectible Accounts													75
76	IURC Fee	\$ 73,681	A56	\$	73,681	\$		73,681	A56	\$	73,681	A56		76
77		33,166,830		\$	22,938,990			27,421,909		-	26,130,964			77
78	Asset Charge	\$ 935,996	A57	\$	196,096	\$		869,756	A57	\$	521,368	A57-S		78
79	Total Operations and Maintenance	\$ 34,102,826		\$	23,135,086	\$		28,291,665		\$	26,652,332			79
80	Depreciation and Amortization	\$ 161,266	A58	\$	(2,377,679)	\$		(59,234)	A58-R	\$	(59,234)	A58		80
81		\$ 5,545,114	A59	\$	5,545,114	\$		5,545,114	A59	\$	5,545,114	A59		81
82	Total Depreciation and Amortization	\$ 5,706,380		\$	3,167,435	\$		5,485,880		\$	5,485,880			82
Taxes														
83	Income Taxes (Federal and State)	(6,340,013)	A60	\$	(4,836,625)	\$		(5,480,735)	A60	\$	(5,341,392)	A60		83
84		175	A61	\$	96,032	\$		175	A61	\$	175	A61		84
85		(23,872,803)	A62	\$	(18,210,995)	\$		(20,636,763)	A62	\$	(20,112,777)	A62		85
86	Other Taxes (IURT and Property Tax)	614,744	A63	\$	621,677	\$		618,788	A63	\$	621,677	A63		86
87		933,537	A64	\$	933,502	\$		933,537	A64	\$	933,537	A64		87
88	Total Taxes	(28,664,361)			(21,396,410)			(24,564,999)			(23,898,781)			88
89	Total Operating Expenses	11,144,845			4,906,111			9,212,546			8,239,431			89
90	Total of All Pro Forma Adjustments (Line 26 - Line 89)	(43,334,946)			(32,326,999)			(36,699,552)			(35,726,437)			90



Vectren Proposal for Reliability Reporting to the OUCC

Recommended Reporting Logistics:

Vectren and the OUCC have worked collaboratively to identify a format and procedures for reliability reports and meetings to assure the reliability programs described in the present Vectren rate case are developed, focused, and implemented to benefit our rate payers. We expect to continue to do so to finalize the actual report content, the timing of and agenda for the regular meetings, and any reasonable modifications brought on by changes in business needs, available technology, reliability program evolution or other issues mutually agreed upon. Initial suggested reporting and meeting criteria are provided below.

- Vectren will provide written reports to the OUCC twice a year, for a period of 3 years.
- Face to face meetings will be held at least once a year.
- Proposed reporting content and format is subject to review and modification after rate case settlement to assure that all appropriate programs are included (as they may be slightly different than those initially proposed and included here).
- Report content and format will be dynamic and evolve through discussions between the OUCC and Vectren.



Annual Reliability Based Maintenance Plan Report

This report (in the fall of the year) will include a high level summary of the programs and the areas planned for focus in the coming year. This proposal is the result of collaborative discussions with the OUCC. Vectren will share results of pertinent engineering and reliability studies including those identified in testimony and to be completed in future. In addition, Vectren will provide technological improvement updates, including the Asset Management Transformation (AMT) project. Any significant effects on operations, staffing, and procedures due to technological improvements will be identified.

- Major programs would be summarized such as:
 - Overhead Reliability Program
 - Include the list of circuits planned for inspection and remediation in the coming year.
 - Pole Inspection Program
 - Summary of plan for inspection for the coming year – may be by circuit, substation, map grid, etc.
 - Distribution Line Clearance Program
 - Areas targeted for tree trim in the coming year - may be by circuit, substation, main lines vs. laterals, map grid, etc.
 - Pole Guy/Grounding Program
 - Summary of plan for inspection for the coming year – may be by circuit, substation, map grid, etc.
 - Underground Pad Mount Equipment Inspection Program
 - Summary of plan for inspection for the coming year – may be by circuit, substation, map grid, etc.
 - Underground Downtown Network Reliability Program
 - Summary of plan for inspection for the coming year – may be by circuit, map grid, city block, etc.
- Some programs will be discussed in lesser detail (but included because of significant expense):
 - Substation Painting Program
 - Transmission Tower Painting Program
- The remaining programs will be combined for reporting purposes and may include the following:
 - Distribution Infrared Inspections
 - Transmission Infrared Inspections
 - Substation Infrared Inspections
 - Pole Attachments
 - AEGIS Recommendations
 - SCADA Inspection
 - Flyover Inspections
 - Newly identified programs
 - Modified or discontinued programs



Annual Report of Previous Year's Results

This report (in the spring) will review the previous year's results and identify any modifications or enhancements in the current year programs that have occurred since the previous reports were prepared. This report will be part of the annual meeting between Vectren and the OUCC.

- Progress on programs will include information such as:
- Reliability Indices, as reported to the IURC annually, with more granular detail and a review of values with and without major events
- Demonstration of progress (may include a more detailed breakdown of indices by outage cause and/or maps showing the areas where programs have focused.)
- Identify known or expected deviations from the plan previously provided.
- General observations
- Lessons learned and how those lessons may be applied.
- Trends identified and resulting activities.

CERTIFICATE OF SERVICE

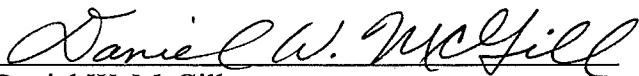
The undersigned hereby certifies that the foregoing Stipulation and Settlement Agreement was served by depositing a copy thereof in the United States mail, first class postage prepaid, addressed to:

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this 20th day of April, 2007.


Daniel W. McGill